COMPASS LEXECON

EXHIBIT 4

Analysis of Economic Efficiencies under Joint Dispatch

Prepared for

Duke Energy Carolinas and Progress Energy Carolinas

I. Executive Summary

A. Overview of Tasks

Compass Lexecon was asked by Duke Energy Carolinas ("DEC") and Progress Energy Carolinas ("PEC") (and collectively, "Companies") to calculate an estimate of the potential cost savings that would be expected to be derived from a combined dispatch of their Carolina electric generating assets located in the two companies' individual balancing authority areas ("BAA") over a 5-year horizon from 2012 to 2016. To accomplish this task, Compass Lexecon used a security-constrained dispatch production cost model to run optimized least-cost production for the individual BAAs on a stand-alone basis and then ran the same model assuming a combined "joint dispatch" across the BAAs holding constant assumptions about load, fuel prices, existing contracts, etc. A net reduction in the total production costs required to serve system loads represents the estimated savings attributable to the joint dispatch.

B. Efficiency Benefits of Joint Dispatch

The estimated potential cost savings of jointly dispatching the DEC and PEC Carolina-based generation fleets are driven largely by optimizing dispatch so as to minimize fuel costs. This optimization results in lower costs of fuel because the joint dispatch creates a larger, more flexible pool of operating assets that is available to draw on when making generation dispatch decisions. Joint dispatch enhances the ability to substitute available capacity at a more efficient plant in one BAA for a more costly unit required to meet load in the other BAA absent the joint dispatch. While these estimated net savings vary in magnitude from period to period, using base case assumptions, savings attributable to joint dispatch over the five year period of approximately $364 million dollars can be expected.

Base Case Savings ($mm)

2012	2013	2014	2015	2016	Total
$38	$49	$64	$97	$116	$364

C. Realization of the Efficiency Benefits Is Not Realistic Absent the Merger

The use of joint dispatch by the companies is an integration benefit that is unavailable absent the merger. By merging, the companies freely integrate the dispatch of their generating units in a way that is not possible absent being a combined organization due to the existence of real time operational constraints and transactions costs.

D. Calculated Efficiency Benefits Are Conservative

The estimated joint dispatch cost savings can be considered a conservative estimate for several reasons. First, multiple sensitivity analyses show that changes in underlying input assumptions generally result in higher estimated benefits. Secondly, the model does not capture the ability of joint dispatch to take advantage of daily fuel and electricity price volatility or potential benefits that can arise for capturing savings within a given hour. Finally, ancillary benefits to the local economy from lower electricity prices have not been analyzed nor has the extent to which future joint planning could further reduce the costs of the merged companies.

II. The Joint Dispatch Analysis

A. The Joint Dispatch Model

A chronological hourly production cost dispatch model was used to calculate the estimated benefits of jointly dispatching the DEC and PEC systems for the years 2012-2016. In particular, a security-constrained dispatch model was used to conduct the analysis to ensure that it could dynamically capture transmission system limitations integrated into the production cost modeling. Moreover, by using a security-constrained dispatch model, the hour-to-hour changes when jointly dispatching the DEC and PEC power systems could be captured.[1]

As Appendix A explains in greater detail, a security-constrained dispatch model allows for optimization of the day-to-day decision making associated with committing generation facilities to serve projected loads. For each day in the analysis, the model determines those generating resources that should be committed, accounting for planned and forced outages, to meet the following day's expected hourly loads as cost effectively as possible. The model simulates least-cost dispatch without sacrificing operational reliability by incorporating a detailed representation of the actual high voltage transmission system. Using a model that can simulate chronological hourly operations subject to actual transmission system limitations was necessary to accurately estimate joint dispatch benefits.

Although the dispatch model captures day-to-day generation unit commitment and hour-to-hour dispatch, it does have some limitations. For example, it does not capture real-time system operational changes that may occur within any particular day. That is, the model does not simulate actions that need to be taken to balance load to accommodate differences between expected and actual loads that may occur in real time. In addition, the model does not predict occasional disturbances that can occur when unexpected generation or transmission outages occur within a particular day. In general it is reasonable to assume that these intra-day disturbances can be more efficiently resolved with a larger integrated system. As previously noted the model results are considered conservative and do not capture this intra-day benefit.

To calculate the potential benefits due to joint dispatch, the analysis was structured to estimate the total variable costs of meeting the load of each of the companies before and after the merger, and to calculate the difference in costs generated by these scenarios. For each company,

[1] Appendix A describes the dispatch model used to conduct the analysis.

the projected total retail and firm wholesale loads for its customers were compiled for each of the years 2012-2016. The analysis then simulated the dispatch of the companies' resources to meet the load, first assuming that the companies independently meet their customers' loads, and then assuming the companies jointly dispatch generating resources to meet their combined loads. A comparison of the projected costs shows that the cost of meeting the loads through joint dispatch is lower than the costs of meeting the loads of each company separately. Therefore, joint dispatch results in positive benefits – i.e., cost savings.

The source of these benefits is the increased efficiency that the companies can achieve by jointly dispatching their generating resources. Through joint dispatch, the complement of resources that are committed to meet loads day-by-day is able to be jointly optimized. This allows for a lower cost portfolio of generation supply to be utilized to meet customer loads. In addition, joint dispatch allows the companies to take advantage of a combined generating resource portfolio on an hour-by-hour basis.

B. Input Assumptions

The modeling analysis focused on the DEC and PEC balancing authority areas in the Carolinas.[2] A variety of modeling input data and assumptions were necessary to carry out the analysis. Some of these data, such as generating unit and transmission system physical characteristics, were readily available to be compiled given that they are based on current and expected facility technology which is known with certainty. Other data, such as expected fuel prices and loads, needed to be forecasted. The primary source of the input data and assumptions used in the analysis were DEC and PEC. Descriptions of the various input assumptions are as follows.[3]

First, to conduct security-constrained dispatch analysis requires that the model use a detailed representation of the high voltage transmission system which includes precise interconnections for all individual generating units and load centers. The companies provided the appropriate transmission system information, including planned upgrades to accommodate future generation plant additions and retirements. These transmission system data allowed the analysis to capture any actual physical limitations that may be encountered when dispatching generation resources.

Next, the companies provided information on all their current and future generating unit capacities. Future generation unit retirements and additions were based on the companies' most recent integrated resource plans ("IRP") and represent known future system supply changes. These data were checked against the transmission system data to ensure all generation units in the two companies' service territories were captured in the analysis (including generation

---

[2] The model also captures transmission system interaction with other interconnected BAAs, however explicit generation dispatch of these other interconnected regions was not modeled in the analysis.
[3] Appendix B summarizes in greater detail the majority of input data and assumptions used for the analysis.

resources not owned by the companies). In addition, any generation units from which the companies have power purchase agreements were included as company resources in the analysis.[4]

In order to ensure that a consistent source of generating unit heat rates (efficiencies) was used in the analysis, heat rate data were obtained from Ventyx Velocity Suite Products ("Ventyx"). The Ventyx heat rate data are primarily derived through the analysis of actual recent operational data collected by the Environmental Protection Agency in association with emissions monitoring. Using these heat rates ensured that expected generation fuel consumption was estimated based on recent operational data. The companies also provided information on expected maintenance and forced outage rates for the generating units.[5] The modeling analysis used these rates to schedule future maintenance requirements and simulate forced outages.[6]

Fuel price forecasts and customer load assumptions also were primarily obtained from the companies. Expected delivered coal and uranium prices were provided for all generating units for each of the years in the analysis. Expected natural gas prices were based on the Nymex Henry Hub natural gas monthly futures contracts as of October of 2010 with adjustments for basis differentials between Henry Hub and the Carolinas. Natural gas prices were adjusted to take into account delivery charges based on DEC and PEC access to natural gas transportation services.[7] Expected distillate fuel oil prices were based on the Nymex number 2 fuel oil futures contracts prices as of October of 2010.[8]

Each company provided total (retail and wholesale customer) hourly load data served by resources owned or located in the company BAAs. Expected changes in wholesale load obligations and expected future growth in load obligations were obtained from the companies. Known changes in firm wholesale load obligations were incorporated into the analysis. Expected load growth forecasted by the companies as reported in their IRPs was then used to escalate load over the forecast horizon.

The analysis uses the companies' transmission system interconnections consistent with historic and physical system limitations to establish expected transmission system interchange flows. In the pre-merger dispatch, the transmission system interconnections are assigned and limited, consistent with the companies' pre-existing transmission service agreements. In the

[4] Long-term power purchase agreements are primarily used by PEC.

[5] In cases where company data for individual units were not provided, the model was populated with publicly available North American Electric Reliability Corporation Generating Availability Data System data.

[6] Near-term DEC and PEC maintenance schedules were not used in the analysis. Instead, maintenance was scheduled by the model based on required scheduled outage rates. This eliminated the impact that any particular near term long or short outage may have on the results of the analysis.

[7] In some instances certain gas-fired generation resources are subject to local distribution charges which can significantly increase the delivered price of gas to a particular generating facility.

[8] Various DEC and PEC combustion turbine generating units are able to operate on both natural gas and number 2 fuel oil. In certain instances these generating units are limited to using fuel oil during the winter months in accordance with fuel supply arrangements.

joint dispatch case, the pre-merger transmission interconnections associated with pre-existing transmission agreements is maintained and available to facilitate additional power exchanges. At the same time, joint dispatch power exchanges also take advantage of any additional available transmission capacity to facilitate power exchanges between the companies, taking into account physical constraints on the transmission system.

The analysis does not assume pre- or post-merger that PEC or DEC makes opportunity off-system sales and/or purchases with other interconnected regions. However, the possibility of future opportunity sales and purchases, and their impact on the analysis, would not materially change the results of the analysis. For example, in many cases, off-system sales will still be made post-merger. After the merged companies have met their native demand, if there are resources available at a lower cost than the price the off-system buyer is willing to pay, the merged company will still make the sales. The merged companies still benefit from these sales, while supplying native load at a lower cost than when the companies dispatched separately. Thus, pre-merger off-system sales may be reduced in some instances, but increased in other instances as the improvements and efficiencies from joint operations result in lower marginal costs for the system as a whole.

Also, based on historical data and market observations, opportunities to produce increased value from off-system sales, especially to PJM, occur when natural gas prices rise significantly as they did in 2008. At low prices, such as those seen in 2009 to the present, these opportunities are significantly reduced. Given the relatively low natural gas price forecast used in the dispatch model ($5.23 annual NYMEX strip for 2012) the value creation off-system is not as material as the joint dispatch savings themselves. Furthermore, as discussed below in the sensitivities section, if actual natural gas prices rise over the forecast horizon, both off-system value creation and joint dispatch savings have the potential to increase relative to current fuel prices.

III. Joint Dispatch Modeling Results

A. Description of Results

The results of the joint dispatch analysis show that the merged companies can obtain significant cost savings by using their electric generation supply portfolios more efficiently. These savings are the result of relying on the lowest cost energy available from the companies' combined generation portfolio day-by-day and hour-by-hour. Combining the companies' generation portfolios allows displacement of higher cost energy that would have otherwise been used by each individual company in the absence of joint dispatch. Exhibit No. 1 provides several examples of how the joint dispatch of the companies' combined generation resources creates cost savings.

Exhibit No. 1 shows the projected monthly utilization of the companies' large and small coal fired units, gas fired combined cycle units, and gas/oil-fired combustion turbine units before and after the merger for the years 2012 and 2015.[9] Beginning with 2012, Exhibit No. 1 (page 1 of 8) shows that the DEC large (> 200 MW) coal-fired generating units' utilization increases across the majority of months. During hours when DEC's high efficiency coal-fired generators have excess production capability they can provide lower-cost energy when compared to PEC's somewhat less efficient large coal-fired generators.

In addition, Exhibit No.1 (pages 1, 2, & 3 of 8) shows that there are times when DEC's coal-fired generating units can substitute for PEC's more expensive gas-fired combined cycle generating units (while at other times, depending on system conditions and loads, the opposite substitution of PEC for DEC resources can occur).[10] Finally, there is a variety of substitution where PEC and DEC moderate-cost, intermediate resources (smaller coal and combined cycles) substitute for the more expensive gas and oil-fired combustion turbines that both PEC and DEC have in their portfolios. In these instances, Exhibit No. 1 (page 4 of 8) shows significant reductions in peaking unit utilization that is replaced by resources other than peaking units.

The substitution pattern is similar in 2015, although the monthly production and substitution change in response to load growth and coal plant retirement. As Exhibit No. 1 (page 5 of 8) shows, DEC's large coal-fired generating units' utilization increases across the majority of months. We also see in 2015 that the expected utilization of intermediate and peaking units increases considerably as new gas-fired units come online and older coal units are retired. Thus, Exhibit No. 1 shows that the monthly pattern of substitution becomes more variable.

In 2015, Exhibit No. 1 (pages 6 & 7 of 8) shows that the projected change of utilization of intermediate cost resources (smaller coal and combined cycles) as a result of the merger varies from month-to-month. Sometimes, DEC's generating units utilization increases while PEC's generation units utilization decreases, however there are also months where the opposite occurs. In addition, Exhibit No. 1 (page 8 of 8) shows that there continues to be considerable variation in the substitution of lower cost supply for DEC's and PEC's most expensive gas and oil-fired peaking combustion turbines. At times, both companies' peaking units' utilization declines, while at other times one company's peaking units' utilization increases while the other company's peaking units' utilization declines.

These monthly utilization changes are directly driven by the relative variable costs of the companies' generation resources and the change in monthly load profiles. Because load profiles and outage schedules change significantly from month-to-month, the patterns of substitution vary considerably month-to-month. The results show that it is generally the case that DEC's lower-cost supplies can be better utilized during periods of lower demand when the generating units would not otherwise be producing at maximum output. The results also show that reductions in

---

[9] These two years were selected to provide an example of the change before and after planned resource additions.
[10] This can be seen by observing that in some months DEC's coal unit production increases are not completely offset by PEC's coal unit production decreases. This means that reductions in PEC gas-fired production are occurring as well.

peaking unit utilization are consistently achieved in certain months of the year. However, the intermediate unit changes in utilization are more complicated, as sometimes intermediate units are substituting for higher cost units, while in other times lower cost coal units are substituting for the higher cost intermediate units.

Exhibit No. 2 summarizes the benefits associated with the estimated cost savings that result from the joint dispatch base case. Exhibit No. 2 shows that under base case assumptions the joint dispatch of PEC's and DEC's generation assets to serve consumers in the Carolinas is estimated to reduce the combined companies' dispatch costs by $364 million in nominal terms over the years 2012-2016. This translates to 1-2.5% per annum savings when compared to continued dispatch of the companies' assets to separately meet their customer loads. As demonstrated in the sensitivities section these savings have upside potential under many scenarios.

The joint dispatch savings are not limited to only DEC and PEC. A portion of the projected benefits will accrue to both existing long-term firm municipal and cooperative consumers as well as wholesale customers making short-term purchases in the Carolinas. Municipal and cooperative consumers that are full and/or partial requirements wholesale customers of the companies will see lower fuel costs as a result of joint dispatch. The wholesale market in general can expect a more efficient system to provide overall regional benefits through lower energy prices.

With respect to these long-term firm customers, both DEC and PEC are currently serving a considerable amount of municipal load in the Carolinas under long-term power supply agreements (see Exhibits No. 3 A and B).[11] The joint dispatch analysis includes all of the DEC and PEC long-term firm wholesale customer loads. Thus, in those instances where the companies' joint dispatch results in lower cost energy supplies, wholesale customers with contracts will see benefits. In addition, in those instances where wholesale customer generation assets are managed by the companies, the joint dispatch should allow for better optimization of these contractually managed assets.

Short-term wholesale customers can also expect to benefit from reduced power costs. Although the majority of the wholesale customer load in the Carolinas is already served under long-term agreements that span several years into the future, in general the companies will make available cost-based power supply that will be lower cost due to joint dispatch than it would be otherwise. To the extent wholesale customers make short-term wholesale purchases from the companies or purchase power on pro-rata formula based rates, they can expect power prices to be lower.

---

[11] In some instances municipal power supply assets are also managed by the companies

B. Joint Dispatch Creates Cost Savings

The use of joint dispatch by the companies is an integration benefit that is unavailable absent the merger. By merging, the companies freely integrate the dispatch of their generating units in a way that is not possible absent being a combined organization. Through the implementation of joint dispatch, each company's available electric energy can be used to displace the other's higher cost electric energy whenever cost savings exists without regard to timing or the size of the difference. This level of integration would not be possible to achieve absent the merger.

The difficulty of achieving these benefits absent the merger is due to the fact that the joint dispatch benefits are achieved hour-to-hour (and even minute-to-minute) with very little risk. Even though without combining the companies, DEC, PEC, or both, may have, during any given hour, resources not needed to serve their retail customers, the practical ability to sell this available hour-to-hour electric energy supply into the wholesale market is much more limited. Joint dispatch removes these limitations. Joint dispatch provides a much more transparent view of the other party's portfolio of resources and can alter the commitment of both portfolios to serve the combined load at a lower cost. In a bilateral market, both parties are factoring in risk of conditions changing. Joint dispatch allows the combined portfolio to be adjusted in real time to further optimize when conditions do change.

For example, wholesale market transactions are primarily conducted at least a day ahead of delivery and must incorporate a level of margin that accounts for transaction risks. To the extent beneficial wholesale purchases and sales need to be planned further ahead than a day or week to account for expected generating unit availability and native load requirements, it can be difficult for the companies to consummate such transactions except in those instances where excess supply can be forecasted with certainty. Moreover, where cost savings from joint dispatch are associated with substitution of peaking generation units, which tend to operate for only hours at a time and are subject to real-time dispatch, wholesale market transactions are not granular enough in many instances to allow companies to coordinate supply exchanges. Through the integration of generation operations the companies obtain the control over generating assets that is necessary to capitalize on hour-to-hour, minute-to-minute, or even in some instances second-to-second, cost savings operations. Joint dispatch is how the companies implement the integration and create cost savings.

Finally, the difficulty of obtaining these benefits absent a merger of the companies is evident from the companies' inability to jointly operate in real time as necessary to capture such savings in periods pre-merger. Simply put, the joint dispatch environment of a merged company is a more efficient environment in which to minimize total fuel cost as compared to wholesale market transactions between individual companies.

C. Projected Joint Dispatch Savings Are Conservative

The estimated $364 million in joint dispatch cost savings to be realized by DEC's and PEC's retail and wholesale customers is expected to be a conservative estimate for several reasons. First, input assumptions based on the current economy create conservative estimates of joint dispatch benefits. For example, sensitivity analyses described below show that there are future scenarios where joint dispatch cost savings would be expected to be greater. Second, the joint dispatch analysis cannot explicitly capture all of the benefits that the companies will realize from operating their systems jointly. There will be greater ability to respond cost effectively to real-time dispatch requirements and over the long-run the companies can be expected to find additional savings opportunities through learning and possibly joint planning. Finally, even in instances where it may be the case that the joint dispatch cost savings could be lower than estimated, it will always be the case that cost savings benefits that result directly from the joint dispatch fail to capture other economic benefits that will accrue to the Carolinas. The lower-energy cost benefits of the merger not only directly benefit customers of the companies, but will also be beneficial to all Carolinians by imparting broader benefits to the regional economy.

Sensitivities: First, as would be expected, the estimated benefits will vary by changing the underlying input assumptions. To understand the sensitivity of the results to the input assumptions, the changes in benefits that result from varying important assumptions that affect the modeling results -- fuel prices and load growth -- were calculated. These two assumptions were ideally suited for sensitivity analysis because, for example, the companies currently envision minimal incremental changes to their generation fleet over the next several years beyond what is already captured in the model. That is, future capacity additions and retirements for each company are well known for at least the next five years and the primary drivers of future variable costs will be fuel prices and load growth.

Exhibits No. 4A-E show the joint dispatch savings assuming higher and lower gas prices, higher coal prices, and higher and lower load growth scenarios. While all of the scenarios affect the total calculated savings due to joint dispatch, all modeled scenarios provide positive and substantial benefits. For example, Exhibit 4A shows the results of the high gas price sensitivity analysis. This case assumes natural gas prices are higher by approximately $1.50 in 2012 and $3.00 higher in 2015. A significant increase in joint dispatch benefits occurs when gas prices increase from the base case resulting in projected costs savings over the period 2012-2016 of approximately $629 million in nominal terms or an increase of $265 million over the base case because coal for gas substitution results in a much larger per MWh savings.

Exhibit 4B shows the results of lower assumed natural gas prices. This case assumes that Henry Hub prices for natural gas are a flat $4.00 over the modeling period. This relatively low price scenario results in modeled benefits due to joint dispatch of $312 million, or a reduction of $52 million. The net effects of changing natural gas price assumptions is driven by, for example, the increase in benefits that flow from displacing less efficient natural gas-fired units with more efficient natural gas or coal-fired units in a higher gas price world. Conversely, lower gas prices reduce these potential benefits. Higher coal prices as shown in Exhibit 4C, assumed to be $0.50 higher than the higher-priced individual company coal forecast, similarly reduce modeled joint dispatch benefits by a small amount to $326 million (i.e., a reduction of $38 million).

As shown in Exhibit 4D, at an extremely low assumed load growth of only 0.5% per annum versus a compounded level of 2-2.5% in the base case, benefits would be expected to decline to a net $249 million, a net savings reduction of $115 million relative to the base case. This scenario reflects conservative assumptions about actual future conditions, but still yields substantial positive potential savings from joint dispatch. Higher rates of load growth, assumed to be approximately +1% compounded per annum above the base case, yield modeled benefits of $437 million, or an increase of $73 million as shown in Exhibit 4E.

As shown by these results, when varying important input assumptions there are significant potential increases to the benefits with relatively small potential decreases to the benefits. These asymmetric changes in the benefits result when testing changes in the input assumptions in all cases except an extreme low load growth case. The source of this asymmetry can be traced to the base case assumptions which are driven by recent recessionary economic conditions. Electric demand and natural gas prices are at low levels when compared to prior to the recent recession. To the extent the economy rebounds more rapidly than expected, the merger will create greater benefits than those calculated for the base case. Furthermore, even if recessionary conditions persist, the joint dispatch savings would increase if underlying fuel costs rise due to environmental or other global market conditions.

Additional Real Time Benefits: Second, the joint dispatch analysis is not granular enough to capture the minute-to-minute operations of dispatchers. Generation dispatchers receive data every few seconds allowing them to make real time operational decisions (e.g. adjust generator(s) output to match load; react to unit trips, adjust unit ramp rates, change unit start times, adjust spinning reserve requirements, etc). Efficiencies gained in these real time, or minute-to-minute, operations are not fully captured in the analysis.

In addition, as the companies gain experience operating their generating units and transmission systems with greater integration there will undoubtedly be future opportunities for savings. As the companies operate generation units to meet combined loads they will gain an understanding of how to use these resources in a complementary fashion. Finally, to the extent future system expansion planning can capitalize on the joint operation of the companies' generation and transmission systems, there will likely be additional benefits that cannot yet be identified.

Insulation From Real Time Price Volatility: The model uses forward fuel prices that only vary monthly when making dispatch decisions. This framework assumes the same daily and hourly price for fuel in each hour of the month consistent with the monthly fuel forecast previously described. In practice, daily fuel prices can spike within the month resulting in short-term opportunities not captured in the model. For example, since January 1, 2010 delivered gas into Transco Z5 has ranged from as low as $3.23 per MMBTU to over $19 per MMBTU on a daily basis. The ability to partially mitigate these price anomalies result in joint dispatch savings above and beyond those characterized in this study.

Economic Stimulus: Importantly, the lower energy costs and associated lower prices estimated by the joint dispatch analysis provide additional benefits to the local economy of the Carolinas that is not captured by the dispatch analysis itself. That is, at lower prices, regional economic activity will be encouraged, thus raising local economic output (gross state product) as well as providing for improved employment opportunities.

Overall, as is always the case with analyses that rely on numerous assumptions about future conditions, the benefits estimated by a model such as the one employed here can never be expected to be perfectly forecast. There can be changes in underlying assumptions and there may be aspects of the companies' joint operations that sometimes prevent every single possible beneficial joint dispatch decision from being taken. However, for the reasons discussed herein the benefits can be expected to be conservatively estimated and it is certain that there will be cost savings benefits due to joint dispatch that are positive and significant.

Appendix A

Security Constrained Dispatch Production Cost Model

The joint dispatch analysis utilized the security constrained unit commitment and dispatch model (DAYZER)[12] to simulate expected DEC and PEC generation unit commitment and dispatch on an hourly basis. DAYZER incorporates all the security, reliability, economic and engineering constraints on generation units and transmission system components, allowing the simulation of realistic actual system operations. Thus, DAYZER was programmed to explicitly incorporate a detailed physical representation of all electric generation and transmission in the DEC and PEC balancing authority areas.

The objective of the joint dispatch analysis was to simulate, pre- and post-merger, the security constrained least-cost hourly electricity system dispatch of the DEC and PEC systems for the years 2012-2016. Because the DEC and PEC generation resources are used exclusively to meet customer loads in the Carolinas, the modeling focused on electric generation resources in the Carolinas.[13] The model simulated both a day-ahead generation unit commitment, and an hourly generation unit dispatch, subject to electric system operational requirements. Thus, for each day in the analysis the model first determined the least cost mixture of generation resources that need to be committed (available) to meet the following day's loads and then determined the least-cost hourly dispatch of the committed resources.[14]

The model takes into account the following factors when determining generation unit dispatch: (1) transmission security constraints (n-1) including any second contingency constraints if applicable; (2) operating reserve requirements (spinning and non-spinning reserves, automatic generation control and quick start reserves); (3) transmission losses; (4) generation unit ramping constraints and minimum up and down times; (5) hourly hydro-electric schedules; (6) pumped storage optimization; and, (7) generation unit start-up, no load and variable costs.

The model requires numerous inputs which are summarized as follows:

1) Generation unit characteristics and input costs:
    - o Generation unit characteristics
        - Capacity (MW)--vary with season as appropriate and for hydro-electric units vary hourly based on typical daily patterns for each month that have been observed historically.

[12] DAYZER is an acronym for Day-Ahead Locational Market Clearing Prices Analyzer.
[13] The model allows for inadvertent power flows between regions subject to transmission costs and physical limitations, but inter-regional dispatch is not modeled.
[14] The model determines a day-ahead security constrained dispatch which does not capture real-time shifts in demand and supply that can require unscheduled dispatch of generation resources.

        - Heat rates, variable operation and maintenance costs, emission rates and expected maintenance and forced outage rates.
        - Plant location and operating constraints (start-up time, ramp up, and associated costs).

    - Long-term power purchase agreement terms and conditions that govern plant dispatch and delivery.

    - Fuel Costs:

        - Coal, natural gas, fuel oil, and uranium prices.

2) Load

    - Hourly total load forecasts for each company allocated to load centers based on company transmission models.

    - Breakdown of retail and wholesale loads as necessary to properly incorporate company obligations in the analysis.

3) Transmission System

    - All major transmission facilities including new transmission lines associated with new generation unit additions.

    - Transmission system contingency requirements as necessary.

    - Operating reserve requirements.

Subject to the operational constraints, the model determined the least-cost mixture of committed generation units to rely upon day-by-day, and hour-by-hour, for the pre- and post-merger scenarios. Then, for each scenario, the total variable costs (composed primarily of fuel costs) were calculated and summed for all hours in each year analyzed. The difference in the total variable costs is the savings attributable to jointly dispatching the generation resources of the two companies.

Appendix B

Joint Dispatch Modeling Assumptions

The following sections provide details associated with the input assumptions used for the joint-dispatch analysis.

Generation Units:

The generation units assumptions can be categorized into the following three categories—existing units, unit retirements and unit additions. Summarization of each of these categories is as follows.

A- Existing Generation Units:

A-1: The characteristics of the existing generation units have been compiled primarily using data obtained from the companies. The companies provided generation unit listings that included capacity ratings, scheduled and forced outage rates, pollutant emission rates, and variable operation and maintenance cost estimates. Generation unit average heat rates were developed based on Environmental Protection Agency continuous emissions monitoring data compiled by Ventyx. Using heat rates from a consistent empirical data source ensured that no biases were introduced in the dispatch process.

A-2: Hydro-electric capacity factors were based on actual historical monthly generation for the last three years as provided by DEC and 10 years as provided by PEC.

A-3: Dual fuel CTs burn only No. 2 fuel oil in the winter period (Nov. – Mar.) except where noted.

A-4: PEC's purchases from the two Congentrix NUGs are at a projected low capacity factor.

A-5: Pump Storage efficiency:
-Bad Creek Pumping Efficiency = 77.35%.
-Jocassee Pumping Efficiency = 78.50%.

Particular generation units' assumptions are as follows:

PEC Specific Generation Units:

A-6: Asheville steam units provide spinning reserve pre-merger.

A-7: Asheville F-frame combustion turbines often run at partial load to provide operating reserves – assume a 15,000 BTU/kWh heat rate at partial load.

A-8: Wayne combustion turbines – Winter: 3 units oil only, 1 gas; Summer: 2 units gas, 2 units oil if needed to run.

A-9: Wayne Units 3, 4, and 5 are dual fuel.

A-10: Richmond combustion turbines – Winter: burn gas.

A-11: Combustion turbines less than 100 MW can provide quick start reserves, CT's above 100 MW do not provide quick start reserves.

DEC Specific Generation Units:

A-12: All CT's provide quick start.

A-13: Non-Pump storage hydro units do not provide quick start .

A-14: All dual-fuel CT's run on gas year round.

A-15: Pump storage units are utilized for regulation but do not provide spinning or non-spinning reserves.

Must Commit Generation Units:

A-16: Asheville Steam units should be treated as must commit for voltage support.

A-17: Sutton 3 and Robinson 1 must be running for voltage support.

A-18: Riverbend 4 and 5 have a must commit requirement for voltage support.

B-Generation Unit Retirements:

B-1: DEC and PEC generation unit retirement assumptions are shown in the following table. These assumptions are based on company integrated resource plans.

Unit Name	Unit Type	Zone	Retirement Date	Summer Capacity (MW)	Winter Capacity (MW)
Wansley 8	NCC	Carolina Power & Light W	12/1/2011	160	160
Buck 7	GT	Duke Energy Corp	6/1/2012	25	25
Buck 8	GT	Duke Energy Corp	6/1/2012	25	25
Buck 9	GT	Duke Energy Corp	6/1/2012	12	12
Buzzard Roost 10	GT	Duke Energy Corp	6/1/2012	18	18
Buzzard Roost 11	GT	Duke Energy Corp	6/1/2012	18	18
Buzzard Roost 12	GT	Duke Energy Corp	6/1/2012	18	18
Buzzard Roost 13	GT	Duke Energy Corp	6/1/2012	18	18
Buzzard Roost 14	GT	Duke Energy Corp	6/1/2012	18	18
Buzzard Roost 15	GT	Duke Energy Corp	6/1/2012	18	18
Buzzard Roost 6	GT	Duke Energy Corp	6/1/2012	22	22
Buzzard Roost 7	GT	Duke Energy Corp	6/1/2012	22	22
Buzzard Roost 8	GT	Duke Energy Corp	6/1/2012	22	22
Buzzard Roost 9	GT	Duke Energy Corp	6/1/2012	22	22
Dan River 4	GT	Duke Energy Corp	6/1/2012	0	0
Dan River 5	GT	Duke Energy Corp	6/1/2012	24	24
Riverbend 10	GT	Duke Energy Corp	6/1/2012	22	22
Riverbend 11	GT	Duke Energy Corp	6/1/2012	20	20
Riverbend 8	GT	Duke Energy Corp	6/1/2012	0	0
Riverbend 9	GT	Duke Energy Corp	6/1/2012	22	22
Dan River 3	STc200	Duke Energy Corp	10/1/2012	142	145
Lee ST 1	STc100	Carolina Power & Light E	1/1/2013	74	80
Lee ST 2	STc100	Carolina Power & Light E	1/1/2013	77	80
Lee ST 3	STc+	Carolina Power & Light E	1/1/2013	246	257
Dan River 6	GT	Duke Energy Corp	6/1/2013	24	24
FPL Cherokee Clean Energy	NCC	Duke Energy Corp	6/30/2013	88	88
L V Sutton 1	STc200	Carolina Power & Light E	1/1/2014	97	98
L V Sutton 2	STc200	Carolina Power & Light E	1/1/2014	104	107
L V Sutton 3	STc+	Carolina Power & Light E	1/1/2014	403	411
W S Lee 1	STc100	Duke Energy Corp	10/1/2014	100	100
W S Lee 2	STc100	Duke Energy Corp	10/1/2014	100	102
W S Lee 3	STc200	Duke Energy Corp	10/1/2014	170	170
Cape Fear 5	STc200	Carolina Power & Light E	12/31/2014	144	148
Cape Fear 6	STc200	Carolina Power & Light E	12/31/2014	172	175
W H Weatherspoon 1	STc100	Carolina Power & Light E	12/31/2014	48	49
W H Weatherspoon 2	STc100	Carolina Power & Light E	12/31/2014	48	49
W H Weatherspoon 3	STc100	Carolina Power & Light E	12/31/2014	75	79
Buck 5	STc200	Duke Energy Corp	1/1/2015	128	131
Buck 6	STc200	Duke Energy Corp	1/1/2015	128	131
Riverbend 4	STc100	Duke Energy Corp	1/1/2015	94	96
Riverbend 5	STc100	Duke Energy Corp	1/1/2015	94	96
Riverbend 6	STc200	Duke Energy Corp	1/1/2015	133	136
Riverbend 7	STc200	Duke Energy Corp	1/1/2015	133	136

C-Generation Unit Additions:

C-1: DEC and PEC generation unit addition assumptions are shown in the following table. These assumptions are based on company integrated resource plans.

Unit name	Unit Type	Zone	Installation Date	Summer Capacity (MW)	Winter Capacity (MW)
Buck Combined Cycle	NCC	Duke Energy Corp	1/1/2012	620	677
Cliffside Steam 6	STc+	Duke Energy Corp	10/1/2012	825	843
Wayne County Combined Cycle	NCC	Carolina Power & Light E	1/1/2013	920	1049
Dan River Combined Cycle	NCC	Duke Energy Corp	1/1/2013	620	677
Sutton Combined Cycle	NCC	Carolina Power & Light E	12/1/2013	625	717

Load Data:

Hourly load forecasts have been provided by DEC and PEC with the load distribution provided from the load flow cases provided by DEC.

Load Growth:

For DEC and PEC the following cumulative annualized load growth rate assumptions are applied to the base 2011 peak loads:

Zone	Season	2012	2013	2014	2015	2016
PEC East	S	2.6%	5.5%	8.1%	10.1%	11.9%
DEC	S	1.5%	3.1%	5.2%	7.4%	9.9%
PEC West	S	2.6%	5.5%	8.1%	10.1%	11.9%
PEC East	W	2.5%	5.5%	8.0%	9.9%	11.8%
DEC	W	1.6%	3.3%	5.4%	7.6%	10.2%
PEC West	W	2.5%	5.5%	8.0%	9.9%	11.8%

For DEC and PEC the following peak loads and annual energy consumption are used in the analysis:

Zone		2012	2013	2014	2015	2016
PEC East	Peak Load	12,637.26	12,979.71	13,279.98	13,514.69	13,736.33
	Energy GWh	60,268.49	61,303.23	62,347.63	63,433.69	64,619.81
DEC	Peak Load	19,823.91	20,129.50	20,536.20	20,961.79	21,454.39
	Energy GWh	98,531.43	99,758.88	101,785.61	103,900.37	106,727.93
PEC West	Peak Load	1,097.14	1,128.35	1,155.39	1,176.40	1,195.69
	Energy GWh	5,783.00	5,931.58	6,074.71	6,186.58	6,304.93

PEC loads were adjusted to shift a portion of the load growth into the on-peak in association with PEC wholesale sales agreements. This is achieved by increasing on-peak loads and then adjusting off-peak energy consumption as necessary to match PEC annual energy consumption forecasts.

D-Transmission Contract Assumptions:

D-1: Only firm energy and transmission contracts were modeled (see table below).

D-2: Generation contracts are for energy only, so all operating reserves should be zero, and the cost should be as shown in table below (all contracts are dispatchable).

D-3: A 436 MW transmission contract from PEC East to PEC West through DEC was modeled.

D-4: The Rowan CC contract (150 MW) sinks to PEC West.

D-5: The DEC Cherokee and other renewable contracts are not dispatchable.

D-6: PEC renewable and cogeneration contracts are not dispatchable.

D-7: The Broad River contract sinks to PEC East.

D-8: Cherokee Contract expires on 6/30/2013.

D-9: A 100 MW contract from DEC to PEC East (2011 through 2016) was modeled.

D-10: A PEC East Import contract 250 MW at $50 from SCEG (1-1-2011 through 12/31/2012) was modeled.

D-11: A PEC external purchase contract (SEPA Hydro), 94 MW through 2016.

			Contractual Capacity MW			
Region	Seller	Plant/Unit	Summer	Winter	Start Date	End Date
DEC	Cherokee County Cogeneration Partners, L.P.	Cherokee County Cogeneration	88	88	7/1/1998	6/30/2013
PEC	Southern Power Company	Rowan CC	151	151	1/1/2010	12/31/2019
PEC	Calpine	Broad River 1	160	166	6/1/2001	5/31/2021
PEC	Calpine	Broad River 2	160	166	6/1/2001	5/31/2021
PEC	Calpine	Broad River 3	160	166	6/1/2001	5/31/2021
PEC	Calpine	Broad River 4	168	194.5	6/1/2001	2/28/2022
PEC	Calpine	Broad River 5	168	194.5	6/1/2001	2/28/2022
PEC	SEPA	SEPA Hydro Contract	94	94	12/31/2010	12/31/2012
PEC	SEPA	SEPA Hydro Contract	109	109	1/1/2013	12/31/2038

Operating Reserves Assumptions:

The operating reserves are 371 MW for PEC, 50% spinning and 50% quick start. PEC West has 100 MW of spin reserve requirement and quick start is met through firm transmission. DEC has only quick start requirement of 506 MW and no spinning reserves.

AGC requirements are 120 MW for PEC and 110 MW for DEC.

Post-merger operating reserves:

CASE	Submarket	Spin	Quickstart	AGC
Post	DEC_PEC	185	691	230

Pre-merger operating reserves:

CASE	Submarket	Spin	Quickstart	AGC
Pre	PEC	185	185	120
Pre	PEC West	100	0	0
Pre	DEC	0	506	110

Emission Allowance Prices:

Emission permit prices for NOX and SOX were obtained from PEC and were used for both companies. The values are shown in the following tables:

NOx Permit Prices		
	Oct-Apr	May-Sep
Year	$/Ton	$/Ton
2010	$363	$408
2011	$275	$308
2012	$867	$1,055
2013	$897	$1,237
2014	$955	$1,211
2015	$986	$1,229
2016	$972	$1,233

SO2 Permit Prices	
Year	$/Ton
2010	$34
2011	$32
2012	$30
2013	$377
2014	$426
2015	$375
2016	$256

Fuel Prices:

Natural Gas:

Natural gas futures prices for Transco Zone 5 plus LDC charges were used in the analysis. The standard LDC charge for all natural gas units is 1.63% of Zone 5 price. Except for the following units:

Unit Id	Unit name	Fuel name	LDC
4409	Buck 7	NG_BK_DAN	2.5
4410	Buck 8	NG_BK_DAN	2.5
4411	Buck 9	NG_BK_DAN	2.5
4914	Dan River 4	NG_BK_DAN	2.5
4915	Dan River 5	NG_BK_DAN	2.5
4916	Dan River 6	NG_BK_DAN	2.5
5315	W S Lee GT8	NG_LEE	3.8
5409	W S Lee GT7	NG_LEE	3.8
6704	Riverbend 10	NG_RBEND	4.9
6705	Riverbend 11	NG_RBEND	4.9
6710	Riverbend 8	NG_RBEND	4.9
6711	Riverbend 9	NG_RBEND	4.9

Coal Prices:

Coal Price forecasts for both DEC and PEC were provided by the companies.

Oil Prices (Fuel Oil No. 2):

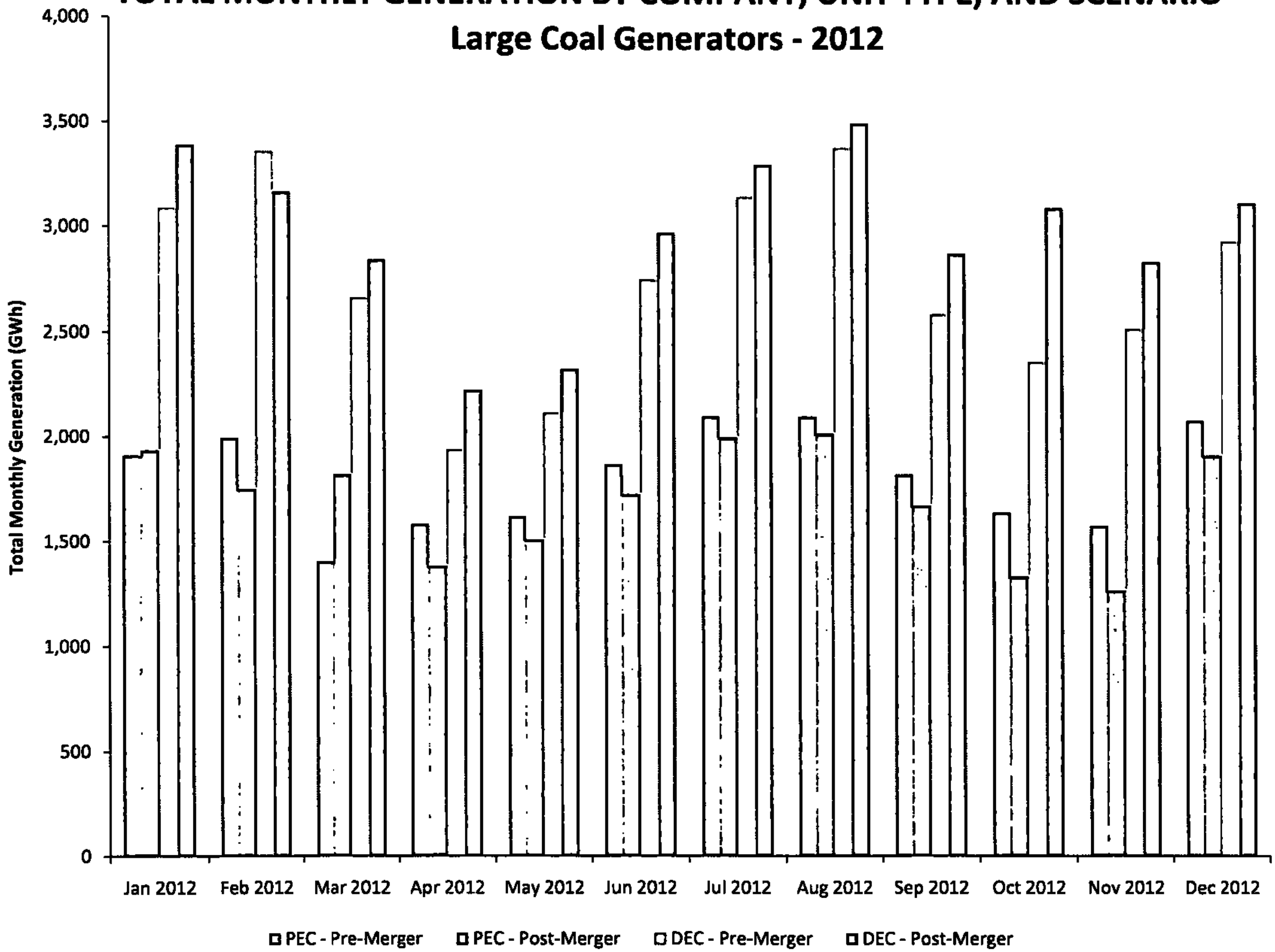
Oil prices are from NYMEX futures for heating oil #2.

Transmission Model:

DEC 2015 load flow models were used for 2012-2016 simulation. It was assumed that the load flow case included all DEC's planned transmission upgrades. Relevant transmission upgrades affecting PEC capacity additions were taken into account. The list of transmission constraints was generated by DAYZER using contingency analysis for the calendar year 2011 and 2015.

Exhibit No. 1

TOTAL MONTHLY GENERATION BY COMPANY, UNIT TYPE, AND SCENARIO
Large Coal Generators - 2012

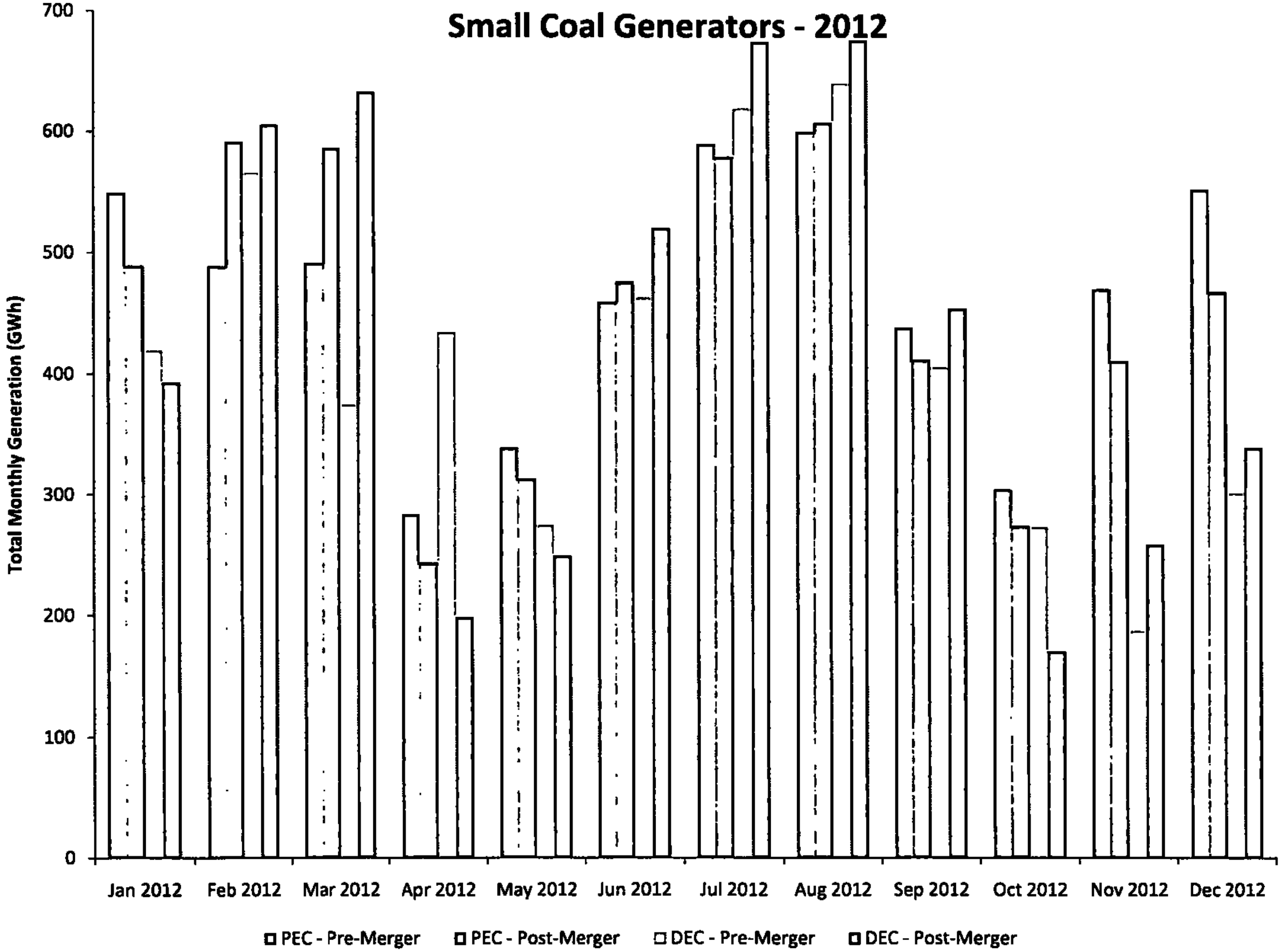


Note: Coal fired generating units greater than 200 MW.
Source: Joint Dispatch Analysis.

Exhibit No. 1

TOTAL MONTHLY GENERATION BY COMPANY, UNIT TYPE, AND SCENARIO

Small Coal Generators - 2012

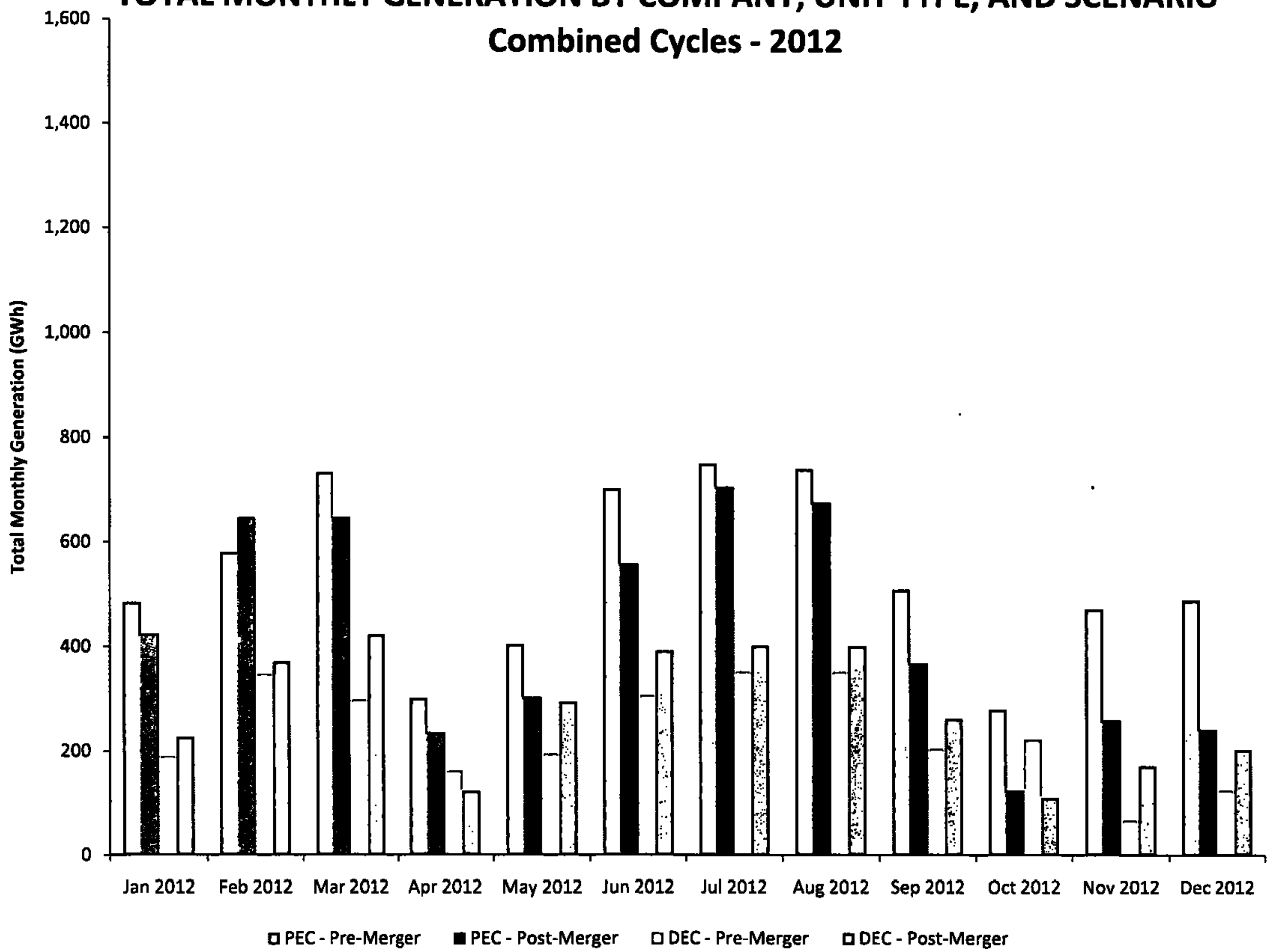


Note: Coal fired generating units less than 200 MW.
Source: Joint Dispatch Analysis.

Exhibit No. 1

TOTAL MONTHLY GENERATION BY COMPANY, UNIT TYPE, AND SCENARIO

Combined Cycles - 2012

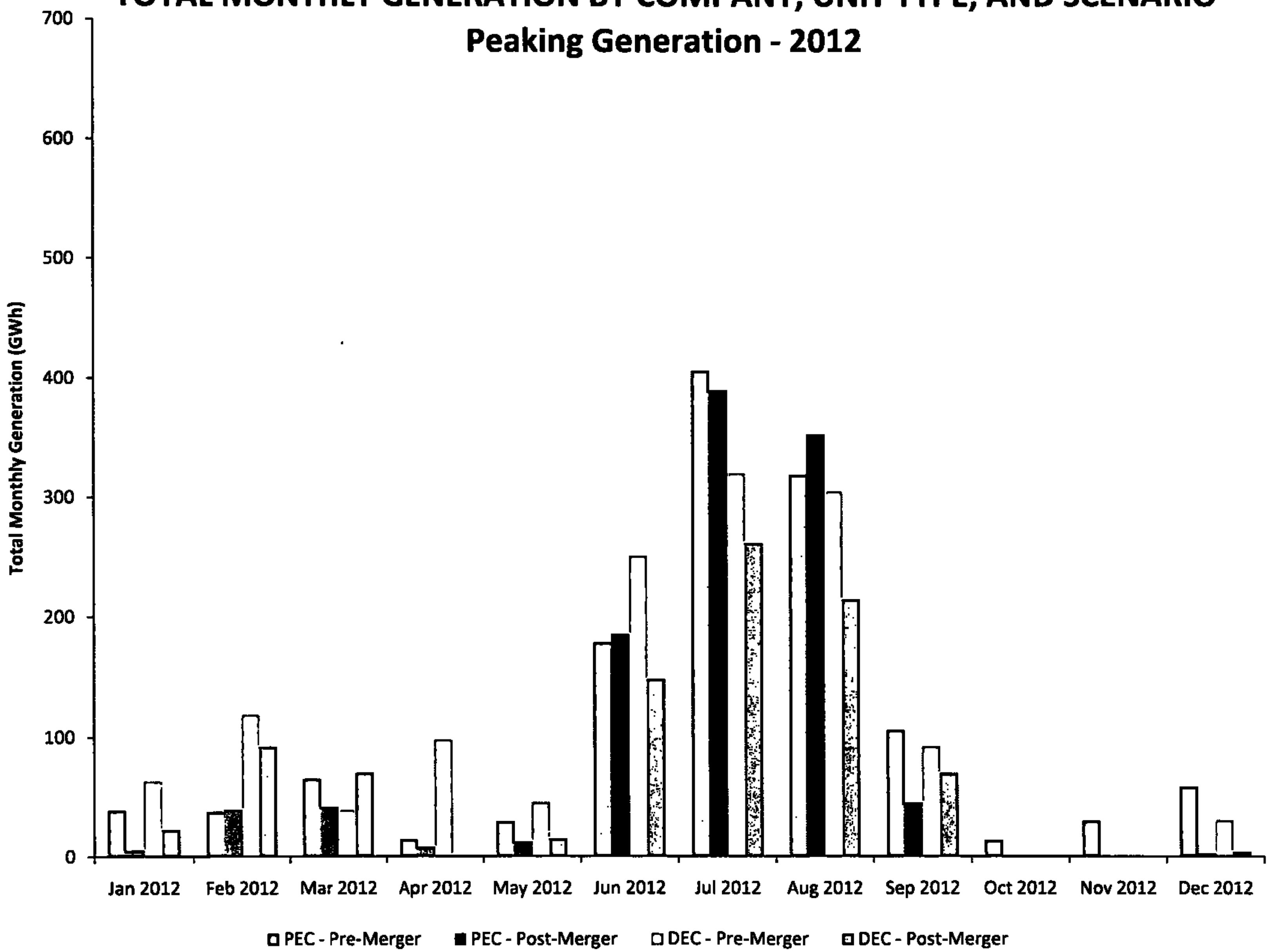


Note: Gas fired combined cycle units.
Source: Joint Dispatch Analysis.

Exhibit No. 1

TOTAL MONTHLY GENERATION BY COMPANY, UNIT TYPE, AND SCENARIO

Peaking Generation - 2012

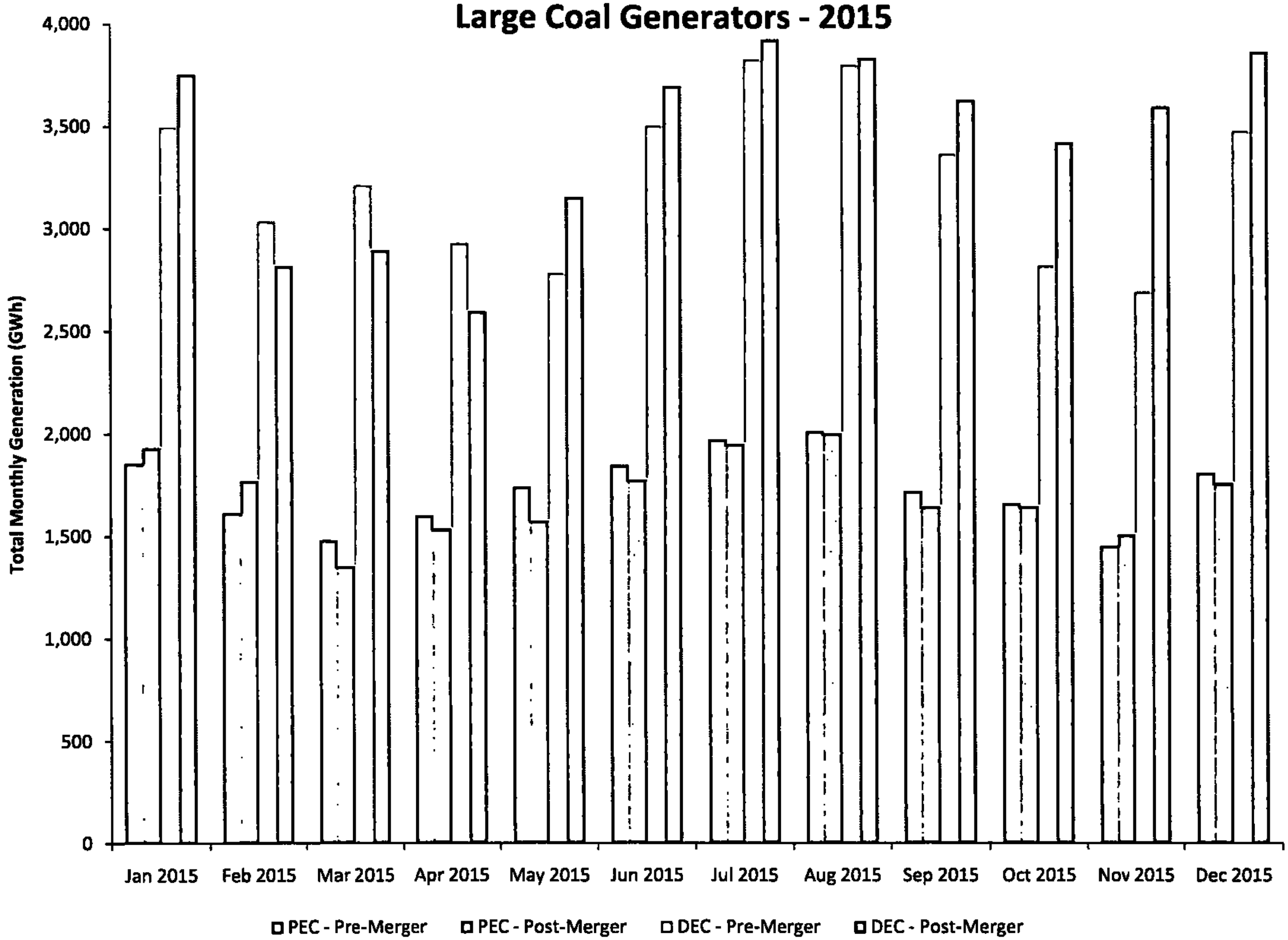


Note: High cost gas/oil fired combustion turbine generators owned by the companies.
Source: Joint Dispatch Analysis.

Exhibit No. 1

TOTAL MONTHLY GENERATION BY COMPANY, UNIT TYPE, AND SCENARIO

Large Coal Generators - 2015

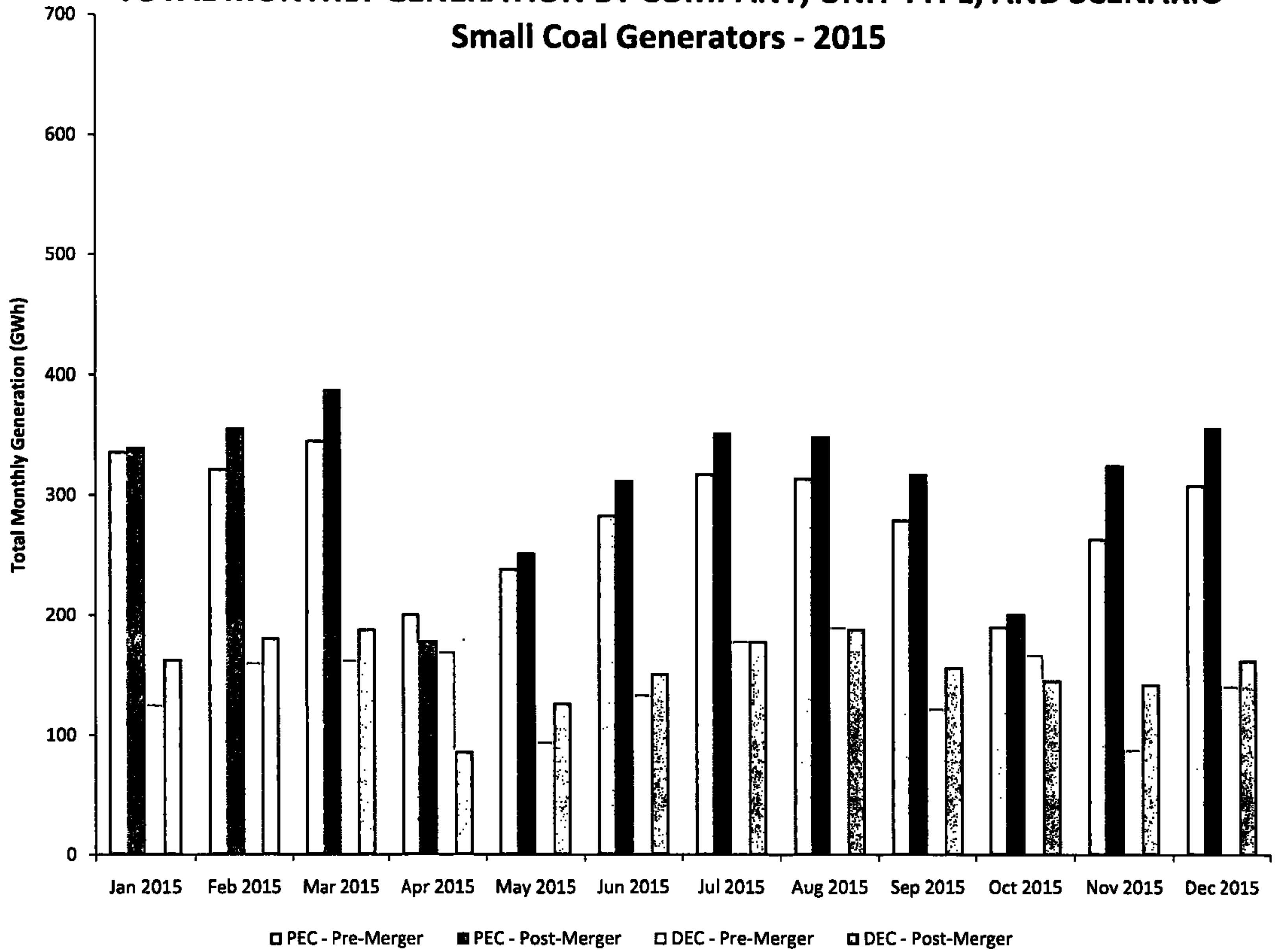


Note: Coal fired generating units greater than 200 MW.
Source: Joint Dispatch Analysis.

Exhibit No. 1

TOTAL MONTHLY GENERATION BY COMPANY, UNIT TYPE, AND SCENARIO

Small Coal Generators - 2015

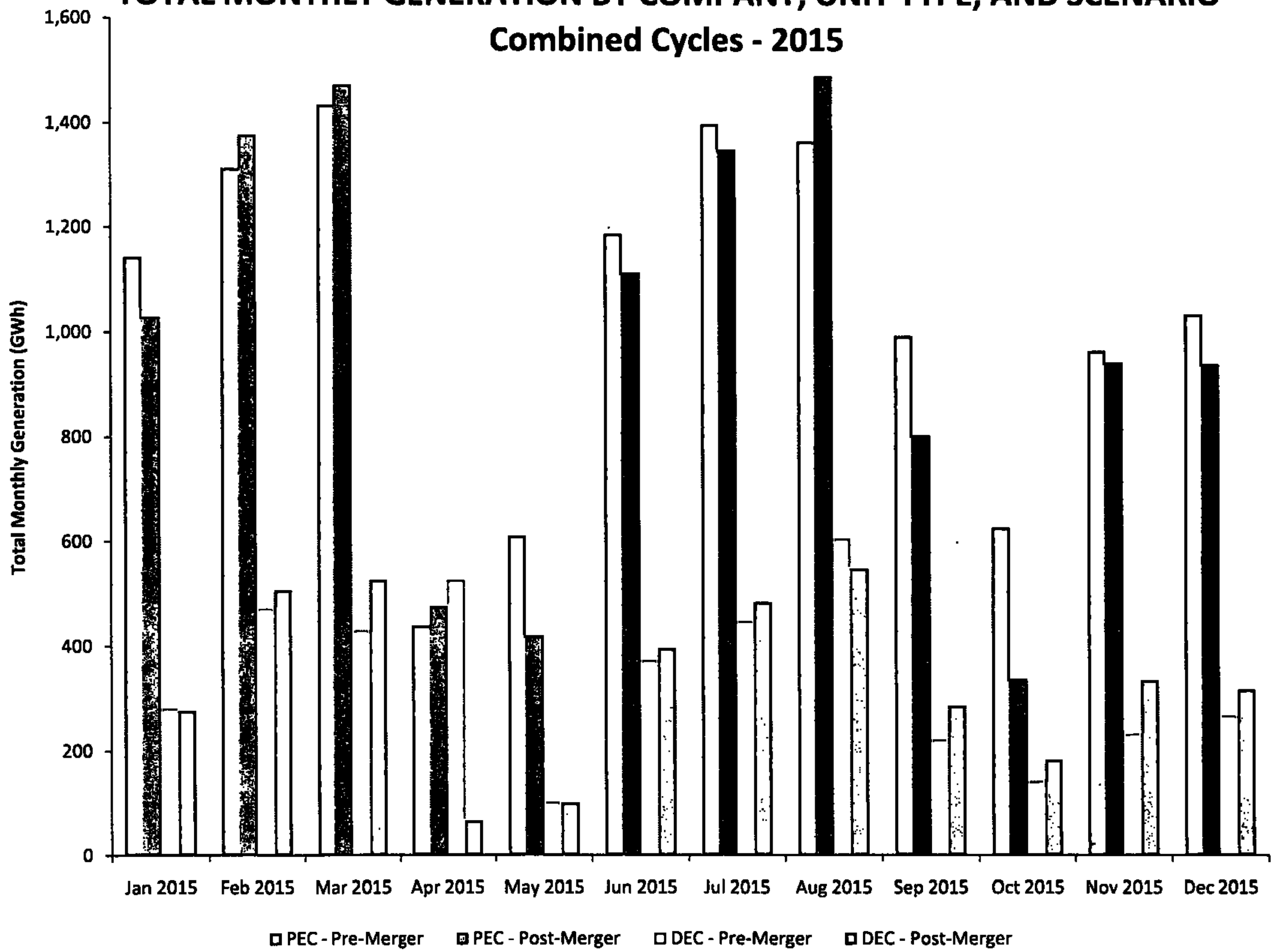


Note: Coal fired generating units less than 200 MW.
Source: Joint Dispatch Analysis.

Exhibit No. 1

TOTAL MONTHLY GENERATION BY COMPANY, UNIT TYPE, AND SCENARIO

Combined Cycles - 2015

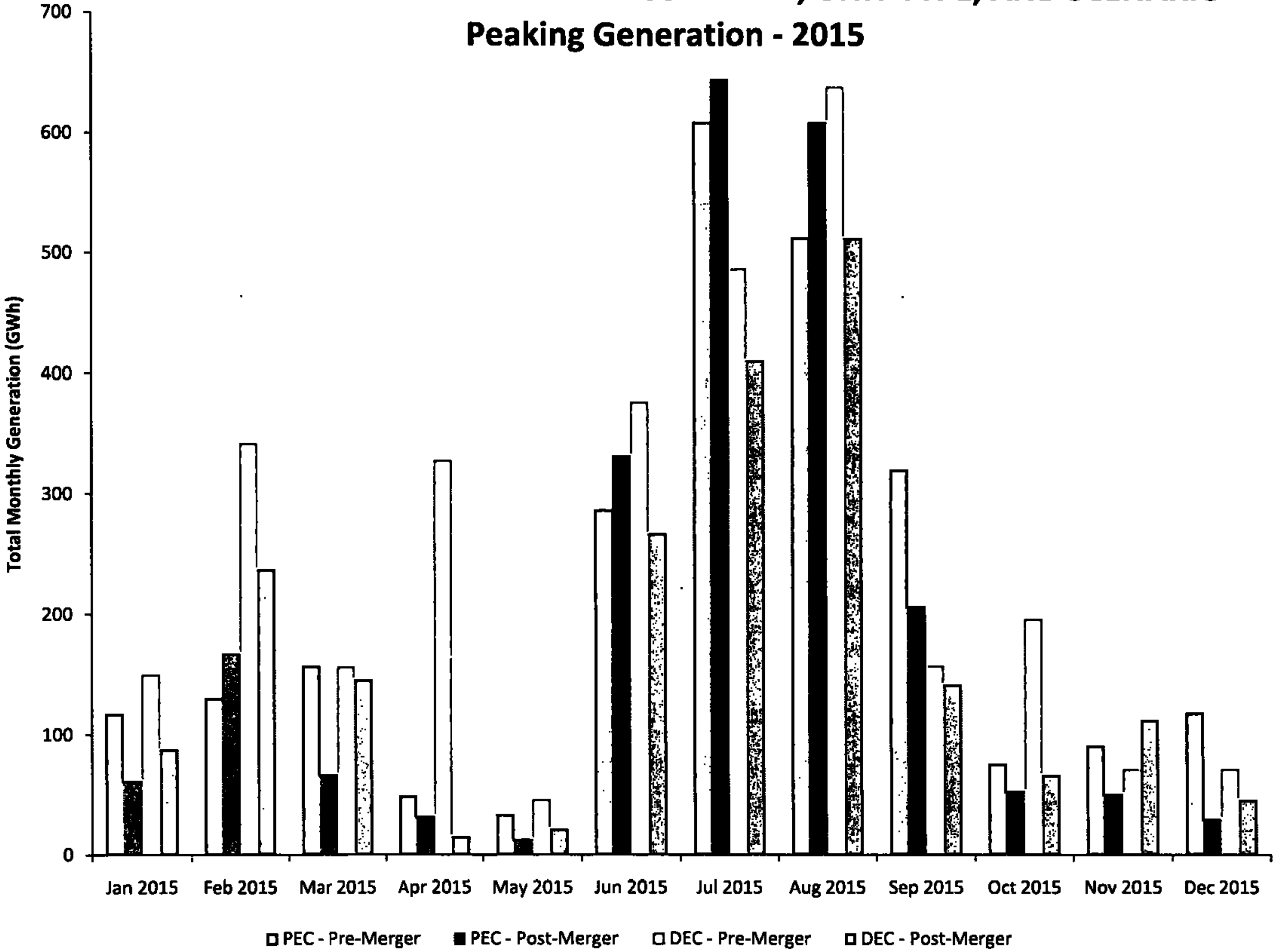


Note: Gas fired combined cycle units.
Source: Joint Dispatch Analysis.

Exhibit No. 1

TOTAL MONTHLY GENERATION BY COMPANY, UNIT TYPE, AND SCENARIO

Peaking Generation - 2015



Note: High cost gas/oil fired combustion turbine generators owned by the companies.
Source: Joint Dispatch Analysis.

Exhibit No. 2

ESTIMATED COST SAVINGS ASSOCIATED WITH DUKE AND PROGRESS JOINT DISPATCH

Base Case ($mm)

		2012	2013	2014	2015	2016
Estimated Cost - No Joint Dispatch		$3,871	$4,110	$4,426	$4,465	$4,715
Estimated Cost - With Joint Dispatch		$3,833	$4,061	$4,361	$4,368	$4,599
Savings	**$**	$38	$49	$64	$97	$116
	%	1.0%	1.2%	1.5%	2.2%	2.5%

	'12-'16
Cumulative Savings	$364

Source: Joint Dispatch Analysis

Exhibit No. 3A

DUKE WHOLESALE CONTRACTUAL OBLIGATIONS

2012

Wholesale Customer	Contract Designation	Type	Contract Term	Capacity (MW)
NC/SC Municipalities	Partial Requirements	Native Load Priority	12/31/2018	326
NP&L Wholesale	Full Requirements	Native Load Priority	Annual renewals. Can be terminated on one-year notice by either party.	14
Blue Ridge EMC	Full Requirements	Native Load Priority	12/31/2021	174
Piedmont EMC	Full Requirements	Native Load Priority	12/31/2021	90
Rutherford EMC	Partial Requirements	Native Load Priority	12/31/2021	156
Haywood EMC	Full Requirements	Native Load Priority	12/31/2021	21
NCEMC	Catawba Contract Backstand	Native Load Priority/ System Firm	Through Operating Life of Catawba and McGuire Nuclear Station	687
NCEMC	Shaped Capacity Sale	Native Load Priority	12/31/2038	72

Note: Customers included in NC/SC Municipalities: City of Concord, NC; Town of Dallas, NC; Town of Forest City, NC; Town of Kings Mountain, NC; Lockhart Power Company; Town of Due West, SC; Town of Prosperity, SC; and the City of Greenwood, SC. Contract designation for the City of Greenwood is for Full Requirements. Customers included in NP&L Wholesale: the Town of Highlands, NC and Western Carolina University.

Source: Duke Energy Carolina's 2010 Integrated Resource Plan.

Exhibit No. 3B
PROGRESS WHOLESALE CONTRACTUAL OBLIGATIONS
2012

Wholesale Customer	Contract Designation	Type	Contract Term	Capacity (MW)
Town of Black Creek, NC	Full Requirements	Native Load Firm	12/31/2017	3.2
City of Camden, SC	Full Requirements	Native Load Firm	12/31/2013	50
Fayetteville Public Works Commission	Partial Requirements	Native Load Firm	6/31/2012	301
Fayetteville Public Works Commission	Full Requirements	Native Load Firm	6/30/2032	531
French Broad EMC	Full Requirements	Native Load Firm	12/31/2012	90
Haywood EMC	Partial Requirements	Native Load Firm	12/31/2021	34
Town of Lucama, NC	Full Requirements	Native Load Firm	12/31/2017	5.3
North Carolina Electric Membership Corporation	NCEMC SOR D	Native Load Firm	12/31/2019	420
North Carolina Electric Membership Corporation	NCEMC SOR A	Native Load Firm	12/31/2015	225
North Carolina Electric Membership Corporation	NCEMC SOR E	Native Load Firm	12/31/2012	225
North Carolina Electric Membership Corporation	NCEMC PPA	Subordinate to Native Load Firm	12/31/2024	300
North Carolina Eastern Municipal Power Agency	Partial Requirements	Native Load Firm	12/31/2017	763
Piedmont EMC	Partial Requirements	Native Load Firm	12/31/2021	21
Town of Sharpsburg, NC	Full Requirements	Native Load Firm	12/31/2017	5.6
Town of Stantonsburg, NC	Full Requirements	Native Load Firm	12/31/2017	5.9
Town of Waynesville, NC	Full Requirements	Native Load Firm	12/31/2015	17
Town of Winterville, NC	Full Requirements	Native Load Firm	12/31/2017	12

Source: Progress Energy Carolina's 2010 Integrated Resource Plan.

Exhibit No. 4A

ESTIMATED COST SAVINGS ASSOCIATED WITH DUKE AND PROGRESS JOINT DISPATCH

High Gas Price Case ($mm)

		2012	2013	2014	2015	2016
Estimated Cost - No Joint Dispatch		$3,984	$4,300	$4,755	$4,995	$5,407
Estimated Cost - With Joint Dispatch		$3,924	$4,216	$4,627	$4,826	$5,218
Savings	**$**	$61	$84	$128	$168	$188
	%	1.5%	2.0%	2.7%	3.4%	3.5%

	'12-'16
Cumulative Savings	$629

Source: Joint Dispatch Analysis

Exhibit No. 4B

ESTIMATED COST SAVINGS ASSOCIATED WITH DUKE AND PROGRESS JOINT DISPATCH

Low Gas Price Case ($mm)

		2012	2013	2014	2015	2016
Estimated Cost - No Joint Dispatch		$3,707	$3,832	$4,055	$4,032	$4,222
Estimated Cost - With Joint Dispatch		$3,678	$3,785	$3,985	$3,959	$4,129
Savings	**$**	$29	$47	$70	$74	$93
	%	0.8%	1.2%	1.7%	1.8%	2.2%

	'12-'16
Cumulative Savings	$312

Source: Joint Dispatch Analysis

Exhibit No. 4C

ESTIMATED COST SAVINGS ASSOCIATED WITH DUKE AND PROGRESS JOINT DISPATCH

High Coal Price Case ($mm)

		2012	2013	2014	2015	2016
Estimated Cost - No Joint Dispatch		$4,179	$4,274	$4,545	$4,774	$5,096
Estimated Cost - With Joint Dispatch		$4,147	$4,230	$4,487	$4,686	$4,992
Savings	**$**	$32	$45	$58	$88	$104
	%	0.8%	1.0%	1.3%	1.8%	2.0%

	'12-'16
Cumulative Savings	$326

Source: Joint Dispatch Analysis

Exhibit No. 4D

ESTIMATED COST SAVINGS ASSOCIATED WITH DUKE AND PROGRESS JOINT DISPATCH

Low Load Case ($mm)

		2012	2013	2014	2015	2016
Estimated Cost - No Joint Dispatch		$3,792	$3,921	$4,098	$3,976	$4,043
Estimated Cost - With Joint Dispatch		$3,758	$3,880	$4,051	$3,914	$3,977
Savings	**$**	$34	$41	$46	$62	$66
	%	0.9%	1.0%	1.1%	1.6%	1.6%

	'12-'16
Cumulative Savings	$249

Source: Joint Dispatch Analysis

Exhibit No. 4E

ESTIMATED COST SAVINGS ASSOCIATED WITH DUKE AND PROGRESS JOINT DISPATCH

High Load Case ($mm)

		2012	2013	2014	2015	2016
Estimated Cost - No Joint Dispatch		$3,995	$4,340	$4,775	$4,983	$5,396
Estimated Cost - With Joint Dispatch		$3,953	$4,287	$4,704	$4,862	$5,246
Savings	**$**	$42	$53	$71	$121	$150
	%	1.1%	1.2%	1.5%	2.4%	2.8%

	'12-'16
Cumulative Savings	$437

Source: Joint Dispatch Analysis

EXHIBIT 5

FUELS SYNERGIES REVIEW

(Confidential)